Stimulation Results From the Newberry Volcano EGS Demonstration

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ABSTRACT

The Newberry Volcano EGS Demonstration in central Oregon, a 3 year project begun in 2010, tests recent technological advances designed to reduce the cost of power generated by EGS in a hot, dry well (NWG 55-29) drilled in 2008. First, the stimulation pumps used were designed to run for weeks and deliver large volumes of water at moderate well-head pressure. Second, to stimulate multiple zones, AltaRock developed thermo-degradable zonal isolation materials (TZIMs) to seal off fractures in a geothermal well to stimulate secondary and tertiary fracture zones. The TZIMs degrade within weeks, resulting in an optimized injection/production profile of the entire well. Third, the project followed a project-specific Induced Seismicity Mitigation Plan (ISMP) to evaluate, monitor for, and mitigate felt induced seismicity. Stimulation started October 17, 2012 and continued for 7 weeks, with over 41,000 m^3 of water injected. Two TZIM treatments successfully shifted the depth of stimulation. Injectivity, DTS, and seismic analysis indicate that fracture permeability in well NWG 55-29 was enhanced by two orders of magnitude.

1.0 Introduction

An Engineered or Enhanced Geothermal Systems (EGS) reservoir is created by injecting large volumes of cold water into hot, low-permeability rock; to induce seismic slip and enhance the permeability of pre-existing fractures. Newberry Volcano is a shield volcano located in central Oregon, about 35 km south of the city of Bend and approximately 65 km east of the crest of the Cascade Range (Figure 1). The Newberry Volcano EGS Demonstration is being conducted on federal geothermal leases and National Forest system lands located in the Deschutes National Forest, adjacent to Newberry National Volcanic Monument. Since the 1970s, extensive exploration activities have been conducted on Newberry Volcano by public and private entities including various geoscience surveys, and then drilling of thermal gradient, slim-hole, and deep, large-bore wells. In 2010, AltaRock Energy, Inc. (AltaRock), in partnership with Davenport Newberry (Davenport), was awarded a DOE grant (Award Number DE-EE0002777) to demonstrate EGS technology at Newberry.

The goals of the demonstration include (Osborn et al, 2011)

1. Create an EGS reservoir,
2. Stimulate multiple zones in existing well NWG 55-29 using AltaRock's proprietary thermally-degradable zonal isolation materials (TZIM) and associated technologies,
3. Test single-well tracers,
4. Confirm EGS reservoir viability through a flow-back test of the injected water,
5. Drill one or two production wells to intersect the EGS reservoir, and
6. Using well NWG 55-29 as the injector, demonstrate EGS viability through a three-month circulation test.

The stimulation of NWG 55-29 began October 17, 2012 and injection ended December 7, 2012, achieving the first two goals. Field activities were suspended over the winter and will be re-started in the spring of 2013 to achieve goals 3 & 4.

2.0 Hydroshearing

AltaRock uses the term hydroshearing (Cladouhos et al., 2009) for the process used in EGS of injecting water at moderate pressure, below the minimum principle stress (Sh_{min}), to cause existing fractures to dilate and slip in shear. A byproduct of shear-slip is the generation of seismic waves that can be used to map fracture location and size. In contrast, tensional fracturing, or hydrofracking, commonly used in the oil and gas industry requires fluid pressures well above Sh_{min}. Permeability enhancement can occur at lower fluid pressures because hydroshearing relies on shear displacement and opening along preexisting fractures, as opposed to hydrofracking that creates entirely new fractures or opens pre-existing fractures with fluid pressure alone. From an operational viewpoint, there are two important distinctions between hydroshearing and hydrofracking. First, in hydroshearing the stimulation equipment is designed to remain below Sh_{min}. Second, no proppants are used in hydroshearing because irregularities along the fracture surfaces keep the fractures propped open after shear slip.

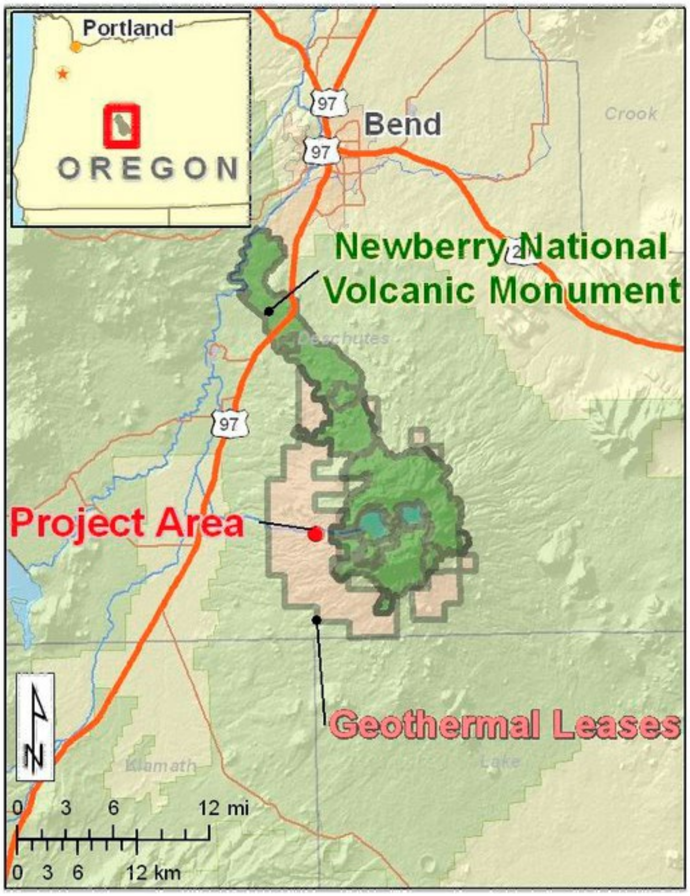

Figure 1. Newberry EGS demonstration 55-29 site location.

While injection induced seismicity in generally illuminates fluid flow paths that connect back to the injection well (Dorbath et al., 2009; Häring et al., 2008), this may not always be the case (Ake et al, 2005), as microseismicity can also be induced by a change in fluid pressure transmitted without fluid movement. This is one reason why tracers were injected as part of the EGS Demonstration, to eventually evaluate connectivity.

3.0 Stimulation Planning

As a part of Phase 1 of the Newberry Volcano EGS Demonstration project, several data sets were collected to characterize the rock volume around the well. Fracture, fault, stress, and seismicity data were collected by borehole televiewer, LiDAR elevation maps, and microseismic monitoring (Cladouhos et al., 2011). Well logs and cuttings from the target well (NWG 55-29) and core from a nearby core hole (USGS N-2) were analyzed to develop geothermal, geochemical, mineralogical and strength models of the rock matrix, altered zones, and fracture fillings (Osborn et al, 2011).

In October 2010, NWG 55-29 was logged using a high-temperature Borehole Televiewer (BHTV) manufactured by Advanced Logic Technology (ALT). The borehole breakouts showed a consistent azimuth indicating that the minimum horizontal stress, Sh_{min} is oriented at 092 ±16.6° relative to true north (Davatzes and Hickman., 2011). This azimuth of Sh_{min}, in combination with the attitude of the majority of natural fractures revealed in the image log, are consistent with normal faulting. The consistency of breakout azimuth, without localized rotations, taken in combination with the extremely low rate of seismicity in the region and the weak expression of natural fractures in the image log, suggests that there has been little recent or active slip on fractures in the vicinity of the well (Cladouhos et al., 2011a; Davatzes and Hickman, 2011).

Determining the magnitudes of the three principle stresses is more difficult. In a normal faulting regime, the maximum principle stress is vertical (Sv) with a magnitude related to the weight of the lithostatic overburden. The minimum horizontal stress (Sh_{min}) at a given depth is best determined from a mini-frac, a well test in which Sh_{min} is determined from the fluid pressure at which tensile fracturing occurs. An accurate mini-frac requires a short (15 m) section of relatively unfractured well bore to be isolated. Isolation allows for sufficient pressure build-up to cause tensile fracturing, provides a narrow depth range over which to calculate Sh_{min}, and ensures that the measured pressure response is due to a tensile failure and not hydroshearing. Because NWG 55-29 has over 1000 m of open hole and isolating a short section would require a drilling rig, it was not feasible to conduct a mini-frac to determine Sh_{min}. Instead, Sh_{min} and the rest of the stress model was constrained based on reasonable geomechanical assumptions derived from injection tests and material properties (Cladouhos et al., 2011a, 2011b; Davatzes and Hickman, 2011). Based on this stress model (Table 1) and a stimulation model, we estimated that a well head pressure (WHP) of 9-11 MPa would initiate hydroshearing and that a maximum WHP of 13-15 MPa would be needed to achieved the goals of the project (Cladouhos et al., 2011b).

Table 1. Stress model.

Component	Gradient (MPa/km)	Direction
Sv	24.1	vertical
SH_{max}	23.5	2° (N-S)
Sh_{min}	14-9 - 15.8	92° (E-W)
Ph	8.8	Fluid pressure

4.0 Stimulation Preparation

Phase 2 of the Newberry EGS Demonstrations began in April 2012 after a Finding of No Significant Impact (FONSI) was issued by the Bureau of Land Management on the project's Environmental Assessment. Phase I planning and permitting is described by (Osborn et al., 2011; Cladouhos et al., 2011b; AltaRock 2011; BLM, 2011).

Stimulation preparation included various field and administration actives. A bidding process was used to obtain field stimulation equipment, including pumps, high-pressure piping, electrical pump control systems, instrumentation and seismic monitoring systems. Field activities included implementing the seismic monitoring network by drilling new monitoring boreholes, prepping the well and well pad for high-pressure stimulation and road maintenance.

4.1 Permitting

Permitting and public outreach efforts included development of comprehensive operation plans for 55-29 stimulation, and working with the BLM, the US Forest Service and the DOE to receive all permits necessary to conduct the stimulation. A series of public meetings were held to inform the public of the plans and ongoing activities for the stimulation and to receive comments and concerns to integrate into planning and regulatory compliance documents.

4.2 Microseismic Array

In Phase 1, a microseismic array (MSA) of 15 stations was proposed in order to map the EGS reservoir and provide real-time monitoring required by the project-specific Induced Seismicity Mitigation Plan (AltaRock, 2011). Starting in late May, after snow melt, four new MSA monitoring holes (NN17, NN19, NN21, and NN24 on Figure 2) were drilled to depths between 213 and 246 m. The depth of these holes was chosen so that the geophones could be installed below the water table, in sections of competent rock at least 30 m long, and below the highly attenuating, cinders and debris flows on the flanks of the Newberry Volcano. In addition, one existing water well (NN18) and three holes drilled in 2010 (NN32, NN09, and NN07 on Figure 2) were used as monitoring holes.

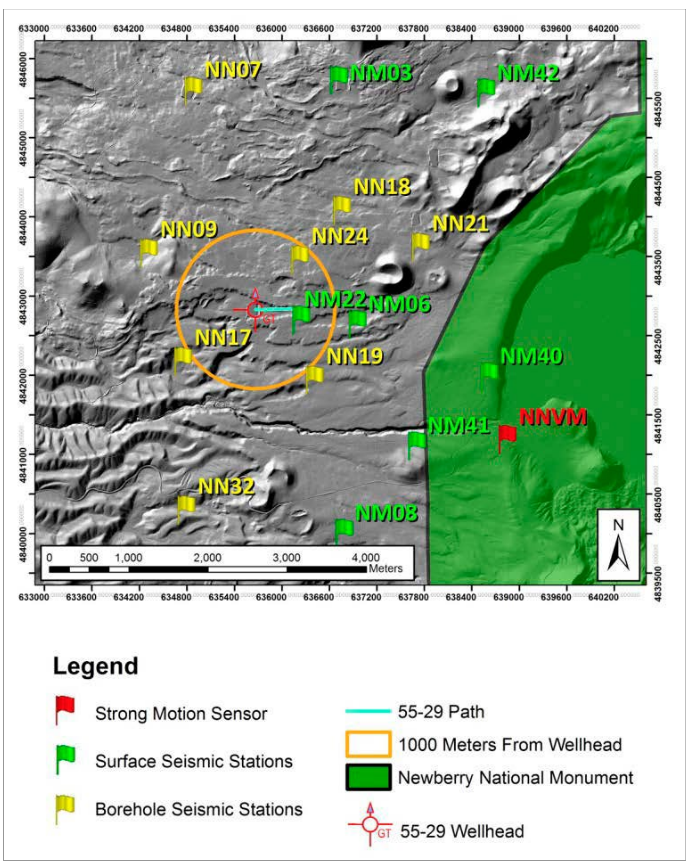

Figure 2. MSA locations, EGS well 55-29, and Newberry National Volcanic Monument (green shading).

Seismic equipment installation began in early August 2012. Two-Hz geophones were installed at seven surface sites and eight borehole sites (Figure 2). The 15 stations stream continuous data via cell phone modem to a server running acquisition software at AltaRock's office in Seattle where the continuous data are saved and archived. Triggered waveforms are sent to Lawrence Berkeley National Lab (LBNL) for locating and publishing to their public website (LBNL, 2013). Microseismic events were also analyzed by Foulger Consulting, and the Pacific Northwest Seismic Network (PNSN) (PNSN, 2013a).

A strong-motion sensor (SMS) was installed, bolted to the concrete floor of a USFS building near Paulina Lake, to monitor any potential shaking at the nearest buildings due to injection-induced seismicity. This site was connected to the Pacific Northwest Seismic Network (PNSN, 2013b) and coded as NNVM (Figure 2).

4.3 Background Seismicity

The regional seismic network at Newberry Volcano has improved greatly in the past two years. In 2009, the only station was NCO, a single-component, short-period seismometer on the east flank and only four microearthquakes (moment magnitudes 1.3-2.2) were detected on Newberry in the prior 25 years (PNSN, 2013a). In 2011, the USGS installed six three-component broadband seismometers and one three-component short-period sensor (PNSN, 2013b). In late August 2012, three of the borehole stations in the AltaRock Newberry MSA (NN19, NN17, and NN21) were also added to the PNSN network. The seismic coverage on Newberry Volcano is now much more comprehensive, with events smaller than magnitude 0.0 being locatable. From August 2012 to April 2013, in addition to locating about 100 events in the EGS swarm (within 1 km of the well), 27 natural events were located (Figure 3), something that would not have been possible prior to the seismic network improvement. Thus, an apparent increase in Newberry Volcano seismicity after the stimulation is due a much improved seismic network, not EGS activities.

4.4 Pumps and Piping

High-pressure pipe and wellhead valves were installed to accommodate injection pressures up to 20 MPa on the surface (Figure 4). Two horizontal centrifugal pumps were leased from Baker Hughes CentraLift to be used as the main stimulation pumps. These stimulation pumps were designed with high-pressure piping and valve arrangement that allowed them to operate in series or parallel. The maximum injection pressure that could be achieved by the equipment was approximately 20 MPa with a flow rate up to 63 L/s. The electrical horizontal pumps, powered by diesel generators, were ideal for the longer stimulation duration and required less maintenance compared to positive displacement pumps.

A booster and sump pump system was rented to provide positive pressure to the stimulation pump inlet. The discharge from the stimulation pumps flowed through high pressure piping into a wellhead T. An in-line differential pressure meter upstream of the stimulation pumps and a clamp-on ultrasonic flow meter downstream of the stimulation pumps were used to measure flow rate.

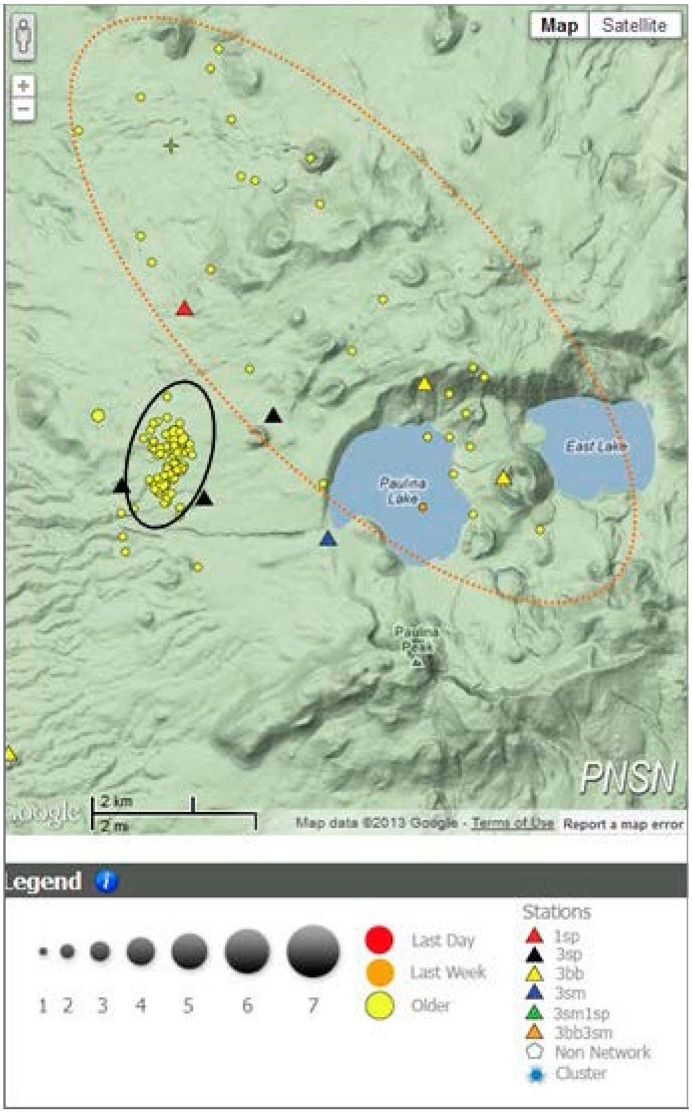

Figure 3. Nine months of microseismicity on Newberry located by the regional network (PNSN, 2013a), natural events (orange dashed oval) and EGS-related events (black, solid oval).

Pressure transducers and temperature sensors also continuously recorded information to the onsite control room. The injection water was near ambient temperature, sourced from a water well next to 55-29. Downhole temperature was monitored by a fiber optic cable configured for Distributed Temperature Sensing (DTS), which provided a means to monitor relative flow rates continuously in the well and thus the depth of fluid exit points. The stimulation was conducted rig-less -- without drill pipe or packer in the hole.

TZIM were staged on site and fed into the intake of stimulation pumps using a blending unit and booster pumps. AltaVert 154 (Petty et al., 2011) was chosen for Newberry due to its stable nature with temperatures between 150° and 200° C and complete degradation between 250° and 300°C. Reactive and nonreactive tracers were also injected in collaboration with Earth and Geoscience Institute at The University of Utah, Pacific Northwest Nation Laboratory and Los Alamos National Lab.

Figure 4. Newberry stimulation site photo. Shown from right to left, A. low pressure inlet (silver pipe with blue joints), B. stimulation pumps (blue), C. high-pressure piping, and D. variable speed drives (green).

5. 55-29 Stimulation Results

5.1 Step-Rate Injection Test

The stimulation started with a step-rate injection test in order to assess the pre-stimulation parameters and determine hydroshearing initiation pressure. The flow rate, well head pressure, and injectivity index for all stages are shown in Figure 5.

Injectivity calculated during the step-rate test averaged 0.37 L/s/MPa, equivalent to injectivity and flow testing results obtained after drilling in 2008. The highest wellhead pressure obtained during the injectivity test was 12.2 MPa with 5.5 L/s injected downhole. Shortly after this wellhead pressure was reached, the stimulation pumps experienced a series of start-up issues due to malfunctions with the electrical drive.

5.2 Injectivity Improvement and TZIM Treatment

Stage I stimulation resumed on October 28. Injectivity improved when injection pressure exceeded 12.4 MPa and the corresponding flow rate reached 20.6 L/s. Moderate pressure injection stimulation continued with injectivity stable at the improved rate until November 14, when sustained drive, pump and DTS issues needed to be addressed. A two week break was taken for required maintenance and assessment

On November 25, both stimulation pumps and DTS were reinstalled and returned to normal operating conditions, though an obstruction at approximately 2,090 m down hole prevented the DTS from being lowered deeper. The improvement in injectivity during Stage I stimulation was approximately 2 L/s/MPa.

Stage II stimulation started with overnight tracer injections on November 24, followed by 6 pills of TZIM from November 25 to 28. Approximately 1,340 kg of TZIM were injected over the period of 4 days as shown in Figure 6. After the first pill was injected, the flow rate decreased slightly while wellhead pressure remained constant. The second, third, fourth and fifth pills were injected over the next two days; each time the concentration and particle size distribution was adjusted slightly to fine-tune the efficacy of the TZIM. Again, flow rate decreased slightly while wellhead pressure remained constant. Pill one through five consisted mostly of fine grained TZIM due to the injection filter

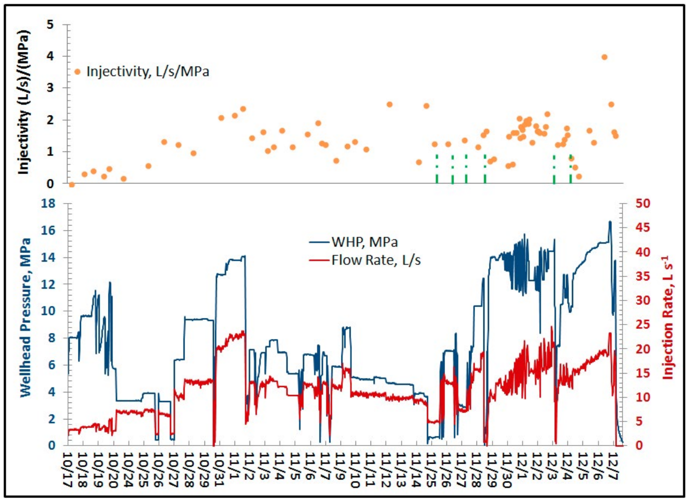

Figure 5. Hydraulic parameters for stimulation of 55-29. Pressure (blue) and injection rate (red). Calculated injectivity (orange) and TZIM injection (Green). Gap in timeline (11/14-11/25) is when stimulation pumps were offline.

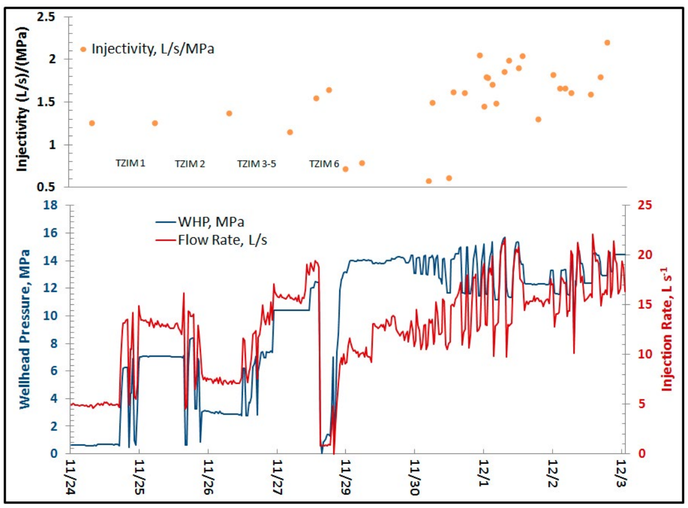

Figure 6. TZIM injection and stage II stimulation. Pressure (blue) and injection rate (red). Calculated injectivity (orange).

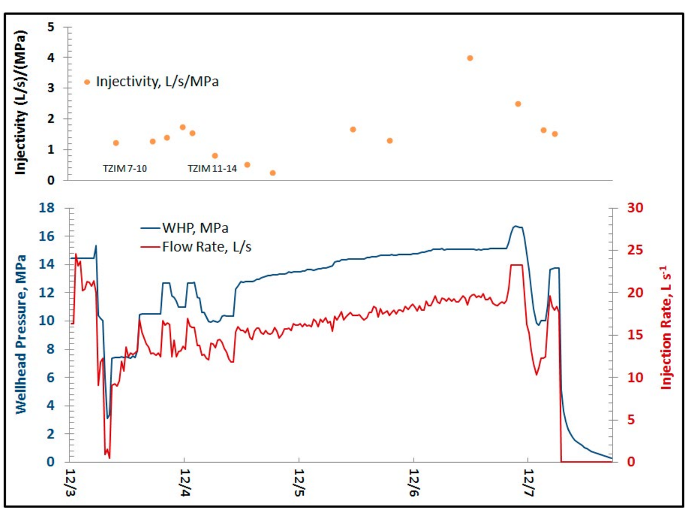

Figure 7. Second TZIM injection and stage III stimulation. Pressure (blue) and injection rate (red). Calculated injectivity (orange).

mesh used to protect the stimulation pumps. In order to test the effectiveness of the course TZIM, the blending unit was disconnected and connected directly to the wellhead on November 28. After 206 kg of course blend TZIM injection, the wellhead pressure increased beyond the pressure capability of the batch mixer blending unit (~1.38 MPa). After restarting the stimulation pumps, the injection rate decreased to approximately 9.5 L/s at 13.8 MPa. The decrease in injectivity as a result of TZIM injection indicated that the fracture zones enhanced in Stage I had been at least 50% blocked and marked the beginning of stimulation of new zones in the wellbore. Wellhead pressure was maintained at 14 MPa with approximately 9 L/s injection rate overnight. The well head pressure was then intentionally cycled between 12.4 and 15.2 MPa (Figure 6). The pressure cycling method seemed to improve injectivity over time. Over the course of the next five days the injectivity of Stage II improved from 0.7 L/s/MPa to 2.2 L/s/MPa. On December 3, the flow rate reached 19.4 L/s with 14.3 MPa corresponding wellhead pressure.

Stage III stimulation began after another set of TZIM treatments -- eight more pills over the next two days (Figure 7). Total TZIM injected in this phase was 1,452 kg. Four consecutive pills were pumped each day. The flow decreased and wellhead pressure increased overnight after both TZIM injection efforts. After TZIM application, the injectivity decreased to 0.26 L s^{-1} MPa^{-1}, actually less than the initial injectivity (0.37 L s^{-1} MPa^{-1}) due to the successful diversion. Well head pressure for Stage III was maintained between 13.3 and 16.7 MPa and the injectivity increased to 2.5 L/s/MPa after two days of high pressure injection. Stimulation pumping continued until the night of December 7, when the well was shut in and allowed to heat-up post stimulation.

Wellhead pressure fall-off data was recorded and analyzed. The improvement in injectivity was approximately 1.3 L/s/MPa during Stage III stimulation. After shut-in, the well did not build static wellhead pressure. Attempts were made to air lift the well and initiate flow but winter weather and well conditions made it impossible to successfully flow test the well.

5.3 Microseismicity

Injection into NWG 55-29 began October 17 and the first microearthquake located in the EGS stimulation zone occurred October 29. Preliminary locations were determined for 179 microseismic events, usually within 8 hours of the event's occurrence. Figure 8 shows the temporal relationship between average WHP and microseismic event magnitudes. Prior to 11/25 WHP changes were due to stimulation pump issues; after 11/25, WHP changes were intentional.

During step-rate testing October 18-20, the well head pressure (WHP) exceeded 12 MPa for just 3 hours. This was an insufficient amount of time or pressure to initiate detectable hydroshearing. Due to stimulation pump problems, the WHP did not exceed 9 MPa again until October 28. After 12 hours at 9.3 MPa, the first definite microearthquake in the EGS stimulation zone occurred near the injection well bore at a depth of ~2.4 km bgs, consistent with a temperature deflection on the DTS. Forty-two hours passed until the next event occurred, by which time the WHP had been increased to 12.5 MPa. Six events followed, indicating that sustained pressure over 12 MPa was required to cause sustained hydroshearing at depth in this well. There was no evidence from the pressure and flow-rate logs (Figures 5,6,7) or the continuously recorded temperature profile, that the minimum principle stress (Sh_{min}) had been exceeded, i.e., no hydrofracking occurred.

After November 1, problems with one of the stimulation pumps necessitated lower pressures, ~ 5 MPa for two weeks and ~0.5 MPa for 10 days (Figure 5). During the lower WHP period, microseismicity continued for 19 days after WHP dropped below 12 MPa. When the stimulation pumps were fully repaired, November 25, seismicity re-initiated at the lower pressure of 7 MPa.

A maximum WHP of 16.7 MPa was reached on December 7, the same day the well was shut-in. Over the following week the rate of seismicity steadily decreased. On December 16 the well was pressured up to 3.9 MPa with an air compressor in an attempt to flow the well. Seismicity increased during and after this pressurization of the well, much like the re-initation of seismicity on November 25.

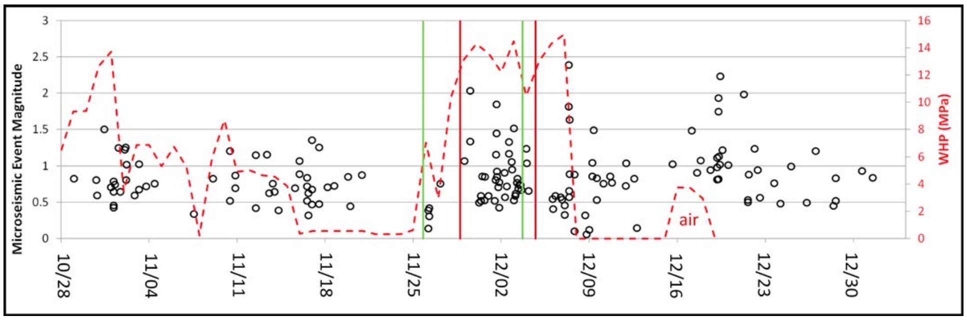

Figure 8. Moment magnitudes (circles) of microseismic events with time compared to averaged WHP (dashed red line). The vertical bars delineate the begin (green) and end (dark red) times for the two TZIM batches.

Table 2. Stimulation parameter summary for 55-29.

	Duration (Hrs.)	Injected volume (m^3)	Maximum Wellhead Pressure (MPa)	Max Injection Rate ($L\ s^{-1}$)	Average Injectivity ($L\ s^{-1}\ MPa^{-1}$)	Total Seismic Event Count	% of Cumulative Moment	Cumulative Seismic Moment (10^{12} N m)
Stage I	960	26,225	14.15	22.9	1.4	54	10.1	1.5
Stage II	190	9,795	15.7	21.64	1.6	97	32.4	4.7
Stage III	80	5,305	16.7	23.28	1.7	129	72.2	10.4
Total	1,230	41,325	16.7	23.28	4.7	179	100	14.6 (12/31/12)

6. Results

Over 41,000 m^3 of ground water was injected during the 7 week span of the stimulation. The maximum injection pressure was 16.7 MPa and preliminary locations were calculated for 179 microseismic events. The injectivity summary and improvement trends are given in Table 2. Wellhead pressures above 12.4 MPa were required to initiate microseismic events and improve injectivity during Stage I stimulation. The decrease in injectivity after TZIM injection signifies that the existing permeable zones were mostly sealed by TZIM. The improvement in injectivity as pumping progressed indicates that new zones were successfully stimulated (Figures 6,7). On average, injectivity per stage after stimulation ranged between 1.4 and 1.7 L/s/MPa. The final cumulative injectivity for 55-29 based on injectivity improvements per stage is estimated to be 4.7 L/s/MPa. A final injectivity test was not performed after TZIM degradation due to weather conditions. Plans have been made to return in the spring after snow melts to perform injectivity testing and log the well. Based on previous lab testing, the time necessary for 100% TZIM degradation should be two to four weeks after shut-in.

In 2008, after drilling, injection and flow tests concluded that the pre-stimulated open hole permeability was extremely low ($<10^{-17}$ m^2, <0.01 mD). A coupled THM model of the stimulation using TOUGH-FLAC at LBNL (Rinaldi et al., 2012) defined the baseline (native-state) horizontal permeability to be 10^{-17} m^2 (0.01 mD).

After shut-in, wellhead pressure was monitored for 24 hours. The pressure fall-off data (Figure 9) was used to conduct a Horner analysis(Horne, 2008) to estimate the transmissivity of the last stimulated zone (other zones were still sealed by TZIM). Using a semi-log analysis approach, the reservoir behavior is anticipated to start after a shut-in time of 0.94 hours. This corresponded to a Horner time of 254 (Horne, 2008). We use Equation 1 from Horne (2008),

$$k = 162.6\frac{qB\mu}{mh} \qquad \text{Eq. 1}$$

where B is the formation factor, μ is Viscosity, q is the flow into the well, h is the stimulated reservoir height, and m is the slope of the Horner plot to calculate a transmissivity of 6.5×10^{-13} m^3. Assuming a reservoir height of 200 m per stage as modeled in (Cladouhos et al, 2011b), the equivalent permeability is 3.2×10^{-15} m^2 (3.27 mD). This result is comparable to the LBNL modeled shear enhanced horizontal permeability of 2×10^{-15} m^2. Both modeled and fall-off

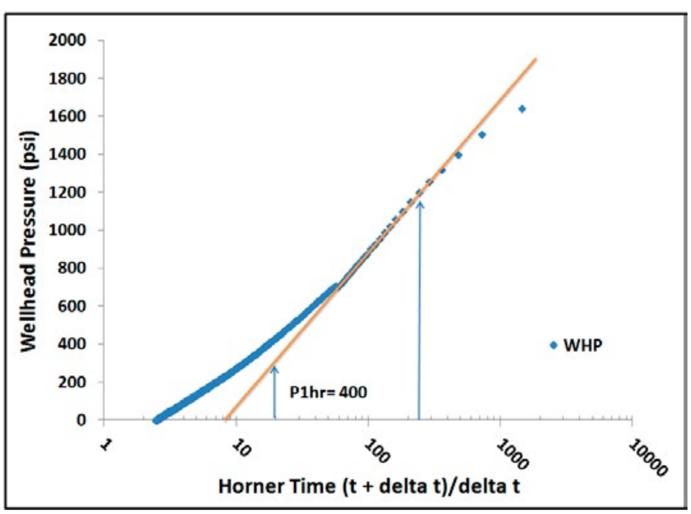

Figure 9. Horner analysis of 55-29 fall-off data before TZIM degradation.

analysis results demonstrate a two orders magnitude increase in permeability after hydroshearing stimulation is applied.

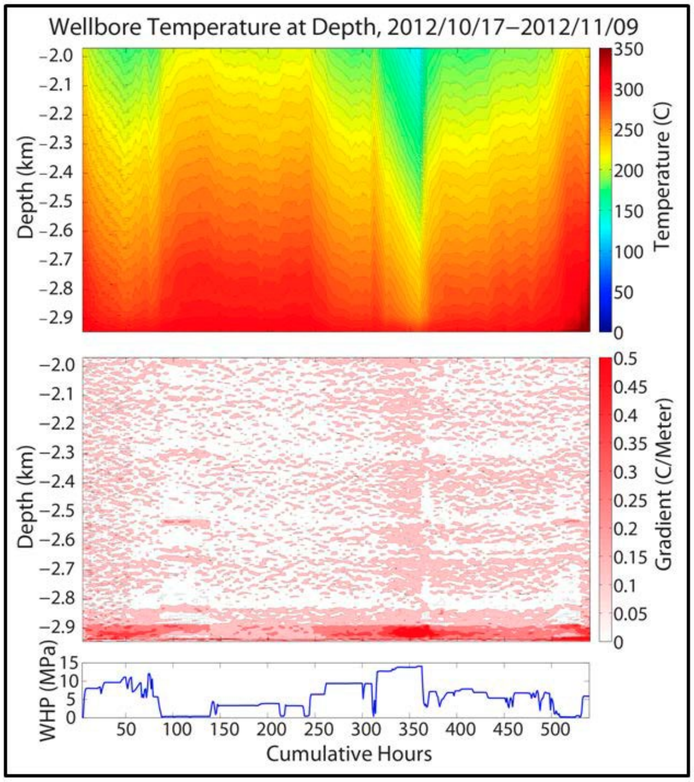

Figure 10. DTS contour visualizing Stage I stimulation.

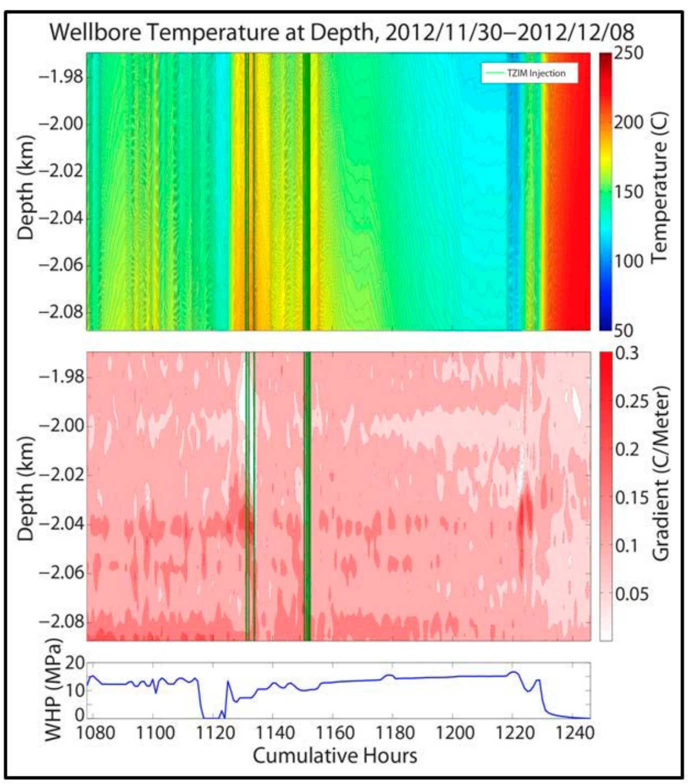

Figure 11. DTS contour visualizing Stage II and Stage III stimulation, including TZIM injection (vertical green lines).

Contour plots of the DTS data, which show evolution of temperature and temperature gradient over time in the open hole interval provide a means to visualize permeability changes. Stage I injection shows one main interval between 2.88-2.95 km taking the majority of the injected water (red streak on bottom of Figure 10).

In Stage I, maximum cooling was achieved between hour 300 and 350, when injection pressure was approximaly14 MPa. The gradient below a depth of 2.89 km during high pressure pumping increased, indicating an increasing amount of fluid exited below 2.89 km. Separations seen within the 2.88-2.95 km gradient plot (Figure 10) suggest that multiple permeable fractures were taking fluid. Several other zones such as 2.55, 2.67 and 2.85 km also showed periodic changes in temperature gradient, suggesting minor fluid loss during stimulation.

The main fluid exit intervals were not monitored during Stages II and III stimulation due to the inability to lower the second DTS below 2.09 km. Contour plots of Stage II (Figure 11) show that during the stimulation a permeable interval beginning at approximately 2.08 km is taking fluid, marked by the change in temperature gradient. This zone is more than 100 m below the casing shoe. Other zones at 2.04 km and 2.06 km also showed small change in temperature gradient.

One goal of the second TZIM treatment on December 3 (marked by green lines) was to seal the 2.08 km zone. The decrease in gradient between 2.08-2.09 km after TZIM injection is an indication of successful TZIM plugging. The constant gradient sustained through the duration of Stage III stimulation and heat-up further validated the effectiveness of TZIM.

6.0 Summary and Future Work

Injectivity, DTS, and seismic analysis all indicate that previously impermeable fractures were enhanced during the NWG 55-29 stimulation. The enhanced fracture network was then successfully sealed with the application of TZIM. This process was repeated to create three distinctive zones in a single wellbore without the use of mechanical isolation devices. Preliminary injectivity and fall-off analysis all suggest improved well bore permeability.

Thus the first two goals of the project, to create an EGS reservoir and stimulate multiple zones using TZIMs, have been achieved. Winter weather prevented the flow back test and tracer recovery in 2012. Field tests planned for summer of 2013 to achieve further project goals include:

- A flow test using a coiled tubing rig to air-lift the cold water column and initiate flow of steam and hot-water. This test will provide samples of fluids that have equilibrated with the formation for geochemical testing. The production rate will quantify the productivity improvement on the well.
- A step-rate injection test, recording WHP and flow rate at three steps, to quantify the total injectivity of the wellbore after the TZIM has fully degraded.
- A logging run by a high temperature video camera to examine areas of concern in the casing and open-hole, such as the depth in the well (2090 m) past which the second DTS could not be deployed.

- Borehole televiewer and temperature logging to characterize the post-stimulation state of the fractures which hydrosheared.
- Complete report on the stimulation results and submittal for formal review to a DOE Stage Gate Review committee. A pass through the stage gate will release funding for drilling production wells.

After the above characterization work is completed, the production well(s) can be designed and drilled so that the final goal of the project, demonstration of EGS viability through a circulation test from an injector to a producer, can be achieved.

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Disclaimer

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